Reliability Enhancement by the Up Gradation of Distribution Switches

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ABSTRACT

Reconfiguration is an indispensable method for loss reduction in power distribution systems and is also used to restore loads in out-of-service areas in case of a fault. Feeder reconfiguration is done to minimize losses for the existing and new topology of the feeder system and for the purpose of maintenance in the distribution system. Reconfiguration of this system is done by changing the status of normally closed sectionalizing switches and normally open tie-switches. We have used daily load curves of different types of distribution consumers, during various types of days (weekdays and holidays) and seasons (summer and winter), are used to obtain the best reconfiguration hours during a day. Then, genetic algorithm (GA) is used to obtain the optimum configuration during each time interval. We have also represented the different methods for assessment of reliability. We have selected switches that contribute to reconfiguration should be remotely controlled in order to have the capability of immediate mode alteration. In order to evaluate the feasibility of automated switch installation, the benefit-to-cost ratio is calculated.

Keywords– Time Varying model, Distribution Reconfiguration, Reliability assessment method, Genetic Algorithm, Benefit cost ratio.

I. INTRODUCTION

Electric utility companies have become very interested in distribution automation. It is apparent that with the increasing complexity of power distribution systems, it is becoming essential to automate some tasks that have always been done manually. As a high proportion of electrical energy is dissipated in distribution systems, the reduction of distribution loss has always been one of the primary issues for economical operation of these systems.

One of the solution is proposed in order to reduce the distribution loss is Network Reconfiguration. Network reconfiguration refers to the closing and opening of switches in a power distribution system in order to alter the network topology, and thus the flow of power from the substation to the customers. There are two primary reasons to reconfigure a distribution network during normal operation. Depending on the current loading conditions, reconfiguration may become necessary in order to eliminate overloads on specific system components such as transformers or line sections. In this case it is known as load balancing. As the loading conditions on the system change it may also become profitable to reconfigure in order to reduce the real power losses in the network. This is usually referred to as network reconfiguration for loss reduction.

Since distribution feeders are composed of different types of consumers and the daily load patterns of these types of consumers are different from each other, system reconfiguration is capable of loss reduction by transferring the load from heavily loaded feeders to other feeders and balancing feeders load. The authors of [1] have considered three cases: 1) hourly reconfiguration; 2) keeping a fixed configuration for the system based on the reconfiguration results for peak loads; and 3) keeping the optimum configuration for average loads as the fixed configuration. Second and third cases are preferred to the first one since it avoids the disadvantages of frequent switching’s. The results of reveal the efficiency of assuming load variation over time, during the optimization process; but keeping the best configuration throughout the whole planning period and, thus, preventing switching actions. Along with the selection of switches their location is also important for loss reduction purposes and to improve reliability.

To obtain this multi objective optimization is performed considering switching cost, loss, and reliability cost to determine the best configuration of the system. The reliability cost is simply modelled by omitting the effect of tie switches. The reliability assessment is done by using probabilistic reliability models of components and implementing the minimal cut set method. We considered daily load curves of different types of consumers in order to find reconfiguration hours during a day. Moreover, different types of days, that is, summer weekdays, summer holidays, winter weekdays, and winter holidays are studied in order to find the switches that contribute to reconfiguration during each of these typical days. The objective function for finding the best configuration is composed of loss and energy not supplied (ENS). Based on the results of reconfiguration, the switches that should contribute to reconfiguration are found. Finally, a cost-benefit analysis is run in order to find out whether the benefits of installing remotely controlled switches can justify its cost or not. It is
assumed that the system is not automated and the study is to survey the feasibility of automating some of the switches.

II. TIME VARYING LOAD MODEL

The time-varying effect model allows scientists to use intensive longitudinal data (ILD) to observe change over time in the factors that influence an outcome. There are different types of distribution consumers like residential, commercial, and industrial. They are considered. Furthermore, the days of the year are divided into four categories: summer weekday; summer holiday; winter weekday; and winter holiday.

Since the daily load curves of distribution loads have time variations, the optimum configuration of the system constantly changes. However, reconfiguring the system based on an hourly schedule might not be logical, since:

1. It needs quite a large number of switches to be remotely controlled, which is not economical.
2. Every switch has a maximum number of permissible switching operations during its lifetime, and frequent switching actions will decrease the switch's life expectancy.
3. Every reconfiguration might lead to load interruption for a short period; this short interruption is negligible for most distribution loads; however, some industrial loads might not tolerate it in case it repeats a lot.
4. It might lead to transient problems[2]

On the other hand, the systems that experience unfrequented reconfigurations mainly work far from their optimum state.

Fig. 1 Typical scaled daily load curve

For determining the best time of reconfiguration during a day, imagine that the scaled daily load curve of a distribution system is as shown by the solid lines in Fig 1. In order to reconfigure the system less than 24 times a day, the 24-h period is divided into a couple of intervals. The number of intervals is a trade-off between the optimum reconfiguration and the number of switching, and can be modified after benefit-cost analysis is executed. Let us divide the 24-h period into two intervals as illustrated in the Fig 2.

Hour’s $h_1$ and $h_2$ are calculated so that the term $|a - b|$ is maximized, where $a$ and $b$ are the average of load values during the first and second time interval, respectively. This technique is expected to reconfigure the system when the daily load curve of the system has its maximum changes. It is worth mentioning that in this study, the average of the load values is only used for obtaining the reconfiguration hours. To obtain the best configuration during each time interval, the exact load curve values are used.

Fig. 2. Daily load profile of different consumer types for different typical day of the year

Fig. 3 Daily load curve of the main feeder during different seasons

III. OBJECTIVE FUNCTION FOR RECONFIGURATION

A. Calculation of Distribution of Energy Loss
Let time interval of typical day i be divided into a set of 1-h periods, shown as
\[ \{h_1^{d}, h_2^{d}, \ldots, h_n^{d}\} \]

In order to obtain the best configuration during this time interval, the following objective function is calculated for different radial configurations of the system and the configuration with minimum objective function is chosen.

\[
f^{i,d} = \sum_{h \notin \{h_1^{d}, h_2^{d}, \ldots, h_n^{d}\}} (W_L E^{Loss^h} E^h + W_R E^{ENS^h} VOLL) \]

where \( h \in \{\text{summer weekday, summer holiday}\} \)
\( i \in \{\text{winter weekday, winter holiday}\} \)
\( d \in \{1, 2, \ldots, n_d\} \).

Here \( E^{Loss^h} \) is the total distribution energy loss through lines during hour h; \( E^h \) is the energy price during this hour; \( n^d \) is the number of time intervals during a day, which is calculated using the technique previously presented; and VOLL is the average value of lost load. \( W_L \) and \( W_R \) are the weighting factors given to energy loss and reliability index, which make it possible to give preference to one of them over the other. In case the loss optimization is more important than the reliability improvement to the system operator, \( W_R \) should be larger than \( W_L \) Otherwise, should be bigger. They could be obtained using methods, such as the analytical hierarchy process. ENS \( ^h \) is the energy not supplied, which is obtained as [3]

\[
ENS^h = \sum_D U_D^{bh} P_D^h, \quad \forall D \in \{\text{load points}\}. \tag{2}
\]

Where, \( P_D^h \) is the active power of load point D during hour h \( U_D \) is the hourly outage time of the load point

This optimization is explicitly done for all of the typical day types (i.e., summer weekday, summer holiday, etc.). Since the search space for finding the radial configuration that minimizes the mentioned objective function is large and the problem is nonlinear and nonconvex.

The energy loss considered is solely the proportional technical distribution energy loss, which is due to distribution lines. Hence, it is calculated as

\[
E^{Loss^h} = \sum_{b \in B} r_b |I_b^h|^2. \tag{3}
\]

Where, \( r_b \) is the resistance of branch b; \( I_b^h \) is the rms value of the current through the branch during hour h obtained running power flow; and B is the set of all of the distribution system branches.

### IV. RELIABILITY EVALUATION AND ASSESSMENT

Reliability of distribution systems is an important issue in power engineering for both utilities and customers. Reliability is a key issue in the design and operation of electric power distribution systems and load. Reliability evaluation of distribution systems has been the subject of many recent papers and the modelling and evaluation techniques have improved considerably a reliability evaluation can be used to evaluate past performance and predict future performance of the distribution system.

A reliability evaluation study can also identify the problematic components in the system that can impact reliability. The reliability study can also help to predict the reliability performance of the system after any expansion and quantify the impact of adding new components to the system. The number and locations of new components needed to improve the reliability indices to certain limits can be identified.

The reliability assessment is done by using probabilistic reliability models of components and implementing the minimal cutset method. However along with this method some indices are used for reliability.

#### A. Reliability Indices for assessment

Reliability indices of an electric distribution system are functions of factors such as component failures, repairs and restoration times which are random by nature. These indices are, therefore, random variables and can be described by probability distributions. The mean values of the probability distributions associated with the reliability indices are very useful and conventional reliability analysis is normally only concerned with these values. There is, however, an increased awareness of the need to evaluate parameters which give information regarding the variation of the indices around their mean value.

The basic distributed system reliability indices at a load point are average failure rate \( \lambda \), average outage duration \( r \), and annual outage duration \( U \). With these three basic load point indices, the following system reliability indices can be calculated.

**Average interruption frequency index (SAIFI)**

\[
SAIFI = \frac{\sum_i N_i}{\sum_i U_i N_i}
\]

**System average interruption duration index (SAIDI)**

\[
SAIDI = \frac{\sum_i U_i N_i}{\sum_i U_i}
\]

**Customer average interruption duration index (CAIDI)**

\[
CAIDI = \frac{\sum_i U_i N_i}{\sum_i U_i}
\]

**Average service availability index (ASAI)**

\[
ASAI = \frac{\sum_i U_i N_i}{\sum_i U_i}
\]

**Average service unavailability index (ASUI)**

\[
ASUI = 1 - \frac{\sum_i U_i N_i}{\sum_i U_i}
\]

**Energy not supplied index (ENS)**

\[
ENS = \frac{\sum_i L_{ai(i)} U_i}{\sum_i U_i}
\]

**Average energy not supplied index (AENS)**

\[
AENS = \frac{\sum_i L_{ai(i)} U_i}{\sum_i U_i}
\]

SAIFI indicates how often an average customer is interrupted by a power outage. A higher SAIFI indicates a more unreliable system. The CAIDI indicates the average interruption duration for a customer, which is also a measure of system reliability. The ASAI indicates the average service availability, which is a measure of system reliability. The ASUI indicates the average service unavailability, which is a measure of system unreliability. The ENS indicates the total energy not supplied, which is a measure of system unreliability. The AENS indicates the average energy not supplied, which is a measure of system unreliability.

These indices are used to evaluate past performance and predict future performance of the distribution system. The reliability assessment is done by using probabilistic reliability models of components and implementing the minimal cutset method. However, along with this method some indices are used for reliability.
interval where as SAIDI indicates the total duration of interruption an average customer is subjected for a predefined time interval. CAIDI indicates the average time required to restore the service. ASAI specifies the fraction of time that a customer has received the power during the predefine interval of time and is vice versa for ASUI. ENS specifies the average energy the customer has not received in the predefined time.

**B. RELIABILITY ASSESSMENT METHOD**

A wide variety of reliability evaluation methods has been developed so far[4-5], such as state and path enumeration methods, failure-mode-and-effect analysis (FMEA), minimal cut-set method, Monte Carlo and Markov chain model. But here to assess the reliability of radial distribution system, we are combining the minimal cut set method and FMEA method which gives us the opportunity to simply model the behaviour of the tie switches, when faults occur, and considers the stuck probability of switches as well.  

1) **Markov chain model**

The two main approaches used are analytical and simulation. The vast majority of techniques have been analytically based and simulation techniques have taken minor role in specialized applications. The main reason for this is because simulation generally requires large amount of computing time, and analytical models and techniques have been sufficient to provide planners and designers with results needed to make objective decisions. Analytical techniques represent the system by a mathematical model and evaluate the reliability indices from this model using direct numerical solutions. They generally provide expectations indices in a relatively short computing time.

A Markov model is quite popular in the quantitative reliability analysis, and that is suitable to give fair idea about the reliability analysis principle. On the basis of Markov models, a simple formula can be developed that can be used to calculate the reliability of the radial distribution network [33]. The method is called like duration-frequency technique, and the starting point is the failure of the individual component. In a so-called stationary Markov process, it basically operates with two central concepts:

- Failure frequency (λ)
- Repair time (r)

It is assumed for example that a component-wise reliability can only be in one of the following conditions; Condition 1: Component is in the function (in); Condition 2: Component is in repair (out). This is illustrated in two state model diagram in figure 4 represented by 0(component in failed state) and 1(component is in a normal state).

![Transition diagram of component states](image)

Fig. 4: Transition diagram of component states

where,  
\[ \lambda = \text{Number of outages on component in a given period} \]
\[ \text{Total time component is in operation} \]

The figure 5 illustrates expected functional and outage time for a component (so called state cycle). The system can be represented by Markov process and equations developed for the probabilities of residing in each state in terms of state transition rates are as follows.

![Average state cycle](image)

Fig. 5: Average state cycle

The average function time, m, is given by ;  
\[ m = \frac{1}{\lambda} \]

Where,  
\[ m = \text{MTTF, mean time to failure} = \frac{1}{\lambda} \]
\[ r = \text{MTTR, mean time to repair} = \frac{1}{\mu} \]
\[ m + r = \text{MTBR, mean time between failures} = \frac{T}{1/f} \]
\[ f = \text{cycle frequency} = \frac{1}{T} \]
\[ T = \text{cycle time} = \frac{1}{f} \]

The probability of component to be in either one of the two states are as shown in the Fig. 4.

\[ p_0 = \frac{r}{m + r} = \frac{\lambda}{\lambda + \mu} = \frac{r}{T} = \frac{\mu}{\lambda + \mu} = \frac{1}{\sum(\text{down time}) + \sum(\text{up time})} \]
\[ p_1 = \frac{m}{m + r} = \frac{\mu}{\lambda + \mu} = \frac{m}{T} = \frac{1}{\sum(\text{down time}) + \sum(\text{up time})} \]

Where,  
\[ f = \mu p_0 \]
\[ f = \lambda p_1 \]
The concept of MCSs is fairly new and still being explored and developed; the initial concept has developed into a generalized form and its similarity to other network characterizations are discussed. MCSs can be used in conjunction with other constraints-based methods to get a better understanding of the capability of metabolic networks and the interrelationship between metabolites and enzymes/gens.

The concept could play an important role in systems biology by contributing to fields such as metabolic and genetic engineering where it could assist in finding ways of producing industrially relevant compounds from renewable resources, not only for economical, but also for sustainability, reasons.

Minimal cut set analysis is a mathematical technique for manipulating the logic structure of a fault tree to identify all combinations of basic events that result in the occurrence of the top event. These basic event combinations, called cut sets, are then reduced to identify those “minimal” cut sets, which contain the minimum sets of events necessary and sufficient to cause the top event. Starting from load points, searching the upstream node will give us the minimal path of the source node to the load points. The radial configuration of the distribution system guarantees that each node has only one upstream node. As a result, a recursive graph search algorithm can be used to obtain the minimal paths. For simplicity, each minimal path is identified by its switches. This procedure will specify the load points that will be interrupted due to the operation of a switch, which are the load points that have the switch in their minimal path. After finding the minimal paths, minimal cut sets can be identified. Each minimal cut set is a set of system components, which has the following two specifications:

- a load point failure, when all of the components of the cutset are in outage
- load point failure does not occur, in the case where at least one of the cutset components is operating

In order to find the recoverable loads in case of each fault, a similar technique is used to find the shortest path between each tie switch and load point. Each load point can be restored by any tie switch, provided that the shortest path between the load point and the tie switch does not contain any normally closed switches or faulty elements.

For more clarity, this algorithm is applied to one of the feeders of bus 2 of the Roy Billinton Test System (RBTS)[6], which is shown in Figure 6.

In this figure, the minimal path of load point LP20 is B2, S1, S2, and F5. Considering S2 as a normally closed switch, the maneuverable load points by this tie switch will be LP20, LP21, and LP22, which are determined by finding the shortest path between S2 and the load points.

3. Finding reliability-network-equivalent

In this step, the number of system components is reduced, by transforming a proportion of the system to an equivalent component. A similar method can be found. The elements [7], whose outage causes the operation of the same protection devices, are called an island. The elements of an island are considered as an equivalent element, and their equivalent reliability parameters are obtained. Finding system islands reduces the calculation time of the next step, that is, FMEA, due to decreasing the size of the system. In Fig. 10, L29, L30, L31, and L32 make an island, since the outage of any of them results in opening S1.

4. Failure-mode-and-effect analysis (FMEA)

FMEA is based on examining all possible failure modes and their effects on the system. Minimal cut sets make it possible to survey the effect of each failure mode. Three types of outages are considered for static components, which are:

1) Active
2) Outage for preventive maintenance
3) Transient

The active and transient failure of elements causes the operation of the primary protection system, whereas the other type of outage does not affect the protection system. The failure of switching elements is modelled based on the IEEE-493 standard [8], where the switches are assumed to have seven failure types. Four of these failure types are associated with the steady state mode of switch operation, which are: 1) Active 2) Transient 3) outage for preventive maintenance and 4) Passive
The passive failure is very similar to maintenance outage and models the cases when the normally closed switches open with no reason. Three other failure types are associated with the switches, which are modeled by their probability: 1) probability of failure to close on command; 2) probability of failure to open on command; and 3) probability of false operation. As a result, the outage of each load point should be evaluated for all the three failure types of each static component, as well as all seven failure types of each switch, separately, which could take a lot of time.

When a fault occurs, the protection system isolates the faulty part by means of circuit breakers (CBs) or fuses. In a radial distribution system, the opening of CBs results in the interruption of all the downstream users. The faulty component is then isolated by opening the disconnectors on both sides. By closing the CBs and some of the normally open switches, the supply is restored to the un faulty parts. Let us assume the entire process takes \( t_{\text{aM}} \).

After the fault clears, the tie switches are opened, the disconnectors of the faulty part are closed, and the system returns to its normal mode. Let us assume the activities that are done after fault clearance, takes the time \( t_{\text{aR}} \). Consequently, in case a fault occurs in each of the islands detected in the previous step, the load points can be classified as one of the following three categories:

### Healthy points
The load points that are not affected by the fault. These points are the upstream nodes of a protection device. For instance, in Fig. 6, for a fault in the island corresponding to F5, the healthy load points are L16, L17, L18, and L19, provided that S2 is a protection switch (i.e., Breaker).

### Maneuverable points
The load points that are interrupted due to the operation of the protection system, but could be restored by isolation of the faulty island and reconfiguring the system through tie switches. In Fig. 6, a fault in the island corresponding to S1 is isolated by S1 and S2, LP16 and LP17 are supplied by closing B2. LP20, LP21, and LP22 are fed by closing the normally open switch. Therefore, load points LP16, LP17, LP20, LP21, and LP22 are maneuverable points.

### Damaged points
The load points that belong to the faulty island. These load points should be interrupted until the repair or replacement of the faulty element finishes. The load points that do not belong to the faulty island and cannot be restored through maneuver actions are categorized as this type of load point too.

For FMEA, all of the islands detected in the previous step are considered faulty, one by one. Then, for each of the faulty islands, the load points are classified as one of the aforementioned categories. After load point’s classification, the interruption rate and average outage time indices of maneuverable and damaged load points can be obtained as shown in Table I.

### Table I
<table>
<thead>
<tr>
<th>RELIABILITY INDICES OF MANEUVERABLE AND DAMAGED LOAD POINTS</th>
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<tr>
<td>Failure rate</td>
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</table>

In Table I, \( \lambda_{eq} \) and \( U_{eq} \) are, respectively, the equivalent failure rate and outage time of the island. As previously defined, \( t_{\text{aM}} \) is the average time spent on isolation of the faulty points and restoring the healthy and maneuverable points and \( t_{\text{aR}} \) is the average time spent for opening the closed tie switches and closing the isolation switches to transfer the system into its normal mode, after repairing or replacing the faulty element.

### V. SOLUTION METHOD

#### A. Benefit Cost Analysis

A benefit-cost ratio (BCR) is an indicator, used in the formal discipline of cost-benefit analysis that attempts to summarize the overall value for money of a project or proposal. A BCR is the ratio of the benefits of a project or proposal, expressed in monetary terms, relative to its costs, also expressed in monetary terms[9]. All benefits and costs should be expressed in discounted present values.

Benefit cost ratio (BCR) takes into account the amount of monetary gain realized by performing a project versus the amount it costs to execute the project. The higher the BCR the better the investment. General rule of thumb is that if the benefit is higher than the cost the project is a good investment

\[
BCR = \frac{\text{Discounted value of incremental benefits}}{\text{Discounted value of incremental costs}}
\]

In order to reconfigure the system immediately, all of the switches that contribute to reconfiguration during different time intervals should be remotely controlled. This will offer the following benefit to the distribution operator, over N years.

\[
\text{benefit} = \sum_{\text{year}=1}^{N} \sum_{i} n_i \sum_{d \in \{\text{summer weekday, summer holiday}\}} \left[ \lambda_{eq} \left( \frac{f_{i,d}^{\text{base}} - f_{i,d}^{\text{opt}}}{(1 + IR)^{\text{year}}} \right) \right] \]

Where, \( n_i \) is the number of days of the typical day \( i \); \( f_{i,d}^{\text{base}} \) is the value of objective function in case no reconfiguration is performed. \( W_L \) and \( W_R \) are equal to 1; \( f_{i,d}^{\text{opt}} \) is the value of the optimum objective function in case reconfiguration is performed and \( W_L \) and \( W_R \) are set to 1; and IR is the interest rate. The term \( (1+IR)^{\text{year}} \) is encompassed in equation (4), in order to discount annual benefits to the present value. The mentioned benefit should justify the cost of remotely controlled switches, which is equal to...
\[
cost = SC \cdot N_S + \sum_{K=1}^{N_S} \sum_{\text{year}=1}^{N} \frac{MC_k}{(1 + IR)^{\text{year}}} \quad \ldots (5)
\]

In (5), SC is the capital cost of a remotely controlled switch considering the communication and measurement devices; \( N_S \) is the number of remotely controlled switches; and \( MC_k \) is the yearly maintenance cost of switch \( K \), which increases as the number of switching of the switch increases hence, is not equal for different switches of the system.

The benefit-to-cost ratio is simply obtained by
\[
BCR = \frac{\text{benefit}}{\text{cost}} \quad \ldots (6)
\]

Assume \( \eta_{\text{max}} \) is the maximum number of allowable switching operations during the lifetime of a remotely controlled switch; and \( \eta_{\text{op}} \) is the number of yearly switchings of the switch, obtained based on GA results. The switch lifetime in years can be calculated as \( (S_{\text{Life}}) \)
\[
S_{\text{Life}} = \frac{\eta_{\text{max}}}{\eta_{\text{op}}} \quad \ldots (7)
\]

In order to evaluate whether installing remotely controlled switches is economically justifiable or not, \( S_{\text{Life}} \) is calculated for all switches. Furthermore, investment return time, that is, the time when BCR starts to become more than 1, is obtained. In case investment return time is less than the minimum value of \( S_{\text{Life}} \), the project lacks economical justification.

### B. Genetic Algorithm

Genetic Algorithm is a general-purpose search techniques based on principles inspired from the genetic and evolution mechanisms observed in natural systems and populations of living beings [10]. Their basic principle is the maintenance of a population of solutions to a problem (genotypes) as encoded information individuals that evolve in time.

The number of radial configurations of real systems is large. Hence, GA is applied in order to find the optimum configuration during each time interval, since it is considered to be an efficient method for large-scale combinatorial optimization problems. Besides, it has the benefit of avoiding being trapped in local optimums.

The algorithm used in this paper is binary GA. One of the techniques for applying GA is to assign each bit of the chromosomes (0 or 1) to the status of one of the system switches. Then, a large objective function is assigned to the chromosomes that result in no radial topologies, and are infeasible solutions. However, this technique might lead to a GA convergence problem. In this paper, a lookup table is used to assign each chromosome to one of the radial configurations. The number of bits per chromosome should be selected so that the number of chromosomes covers all of the radial configurations of the system. Assume the number of radial configurations of the system is \( K \). Each chromosome of binary GA should have bits, \( \text{where } n \) is the minimum integer number that satisfies \( 2^n \geq K \). Imagine the binary value of a chromosome is \( m \). In the proposed GA, this chromosome is assigned to the configuration corresponding to \((m \text{MOD} 2^n) - 1\), where \( m \text{MOD} 2^n \) is the residue of dividing \( m \) by \( 2^n \). This technique avoids getting caught up in local extremums.

**TABLE II**

**DIFFERENT CHROMOSOME STRUCTURES AND THE ASSIGNED STATES**

<table>
<thead>
<tr>
<th>Chromosome Structure</th>
<th>State Number</th>
</tr>
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<tbody>
<tr>
<td>001</td>
<td>2</td>
</tr>
<tr>
<td>010</td>
<td>3</td>
</tr>
<tr>
<td>011</td>
<td>4</td>
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<td>1</td>
</tr>
<tr>
<td>110</td>
<td>2</td>
</tr>
<tr>
<td>111</td>
<td>3</td>
</tr>
</tbody>
</table>

**Procedure for selecting the switches that should become remotely controlled and its economical evaluation**
VI. CONCLUSION

Daily reconfiguration is assumed to be done for loss reduction and reliability improvement. GA was applied to find the optimum system configuration during each time interval. Based on the results of reconfiguration, the switches that need to become remotely controlled were found, in order to reduce the switching time needed for daily reconfiguration. Finally, BCR analysis was implemented to investigate whether switch upgrade is profitable or not.

There are different methods for assessment of reliability for selecting the switches like Minimal cut set method, Monte Carlo method, Failure mode effect analysis, these methods are very important for assessing and evolution of reliability.

REFERENCES